Appendix F

Wild Rose Simulation

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Introduction

Located in Wyoming, the Wild Rose area (18T 94 R) is operated by BP America. Initial production began in 1975, and as of 2004 the field contained 273 active wells, with cumulative production of 34 bcf. Production from this massively stacked tight sand play (with intermingled coal) is derived primarily from the Mesaverde reservoir, situated at an average depth of 9,800 feet over this study area. Of prominent interest to the operator is the determination of a set of rational development guidelines to maximize the gas rates and minimize the produced water during continued development.

The reservoir simulation effort was performed jointly between Advanced Resources Inc. (ARI) geoscience staff and the engineering staff. In practice, this meant that the initial model was based on reservoir parameters determined from the reservoir characterization efforts. The model was then executed repetitively and matched to historical production using progressively finer adjustments to the inputs. Bulk wellbore permeability was the least constrained input and received the majority of the early attention. Minor adjustments of gas and water relative permeabilities to more accurately reflect the actual water production was the final step of the history match effort.

The permeability matrices of the intra well areas were adjusted between the history match and final forecast simulations. This was required because the significant permeability increases necessary to achieve an acceptable history match gave the overall model an unnatural permeability pattern. Seventy-six wellbore cells were described geostatistically using variography as well as used to conditionally simulate the intrawell areas. The resulting permeability matrix was reintegrated into the model and the final forecast simulation runs were made.

The resulting simulation is believed to geologically and statistically reflect the Wild Rose area and provide a valid aggregate forecast. The variography analysis used for the conditional simulation indicated a significant sill, or short wavelength variability. This was consistent with the small scale faulting observed on the seismic and the sporadic high productivity wells observed in practice. The forecast simulation is held to be statistically valid but contains considerable variability at the cell level (as the field itself does in practice).

Model Setup

To perform this modeling work, the township study area was discretized into a 40 by 40 rectangular grid of 800-foot by 800-foot squares. This grid spacing resulted in the complete coverage of the study area and encompassed 23,000 acres of the play. Vertically, the model contained twenty-three layers of alternating gas- and water-charged sand and coal layers, each layer having spatially variable thicknesses (fig. F-1).

Overall, there were twelve sand and eleven coal layers, with odd number layers (from top to bottom in the reservoir column) being sand bodies. When constructing these alternating sand/coal layers, only immediate sand/coal pairs were permitted to communicate vertically. This procedure emulated the interspersed nature of coal stringers through the sand body.

To populate the grid cells in the model, the geologic team supplied detailed petrophysical data. These variables (spatially and vertically) included, by layer:

- Sand and coal thickness (fig. F-1)
- Sand elevation, subsea (fig. F-2)
- Sand porosity (fig. F-3)
- Sand gas saturation (fig. F-4)

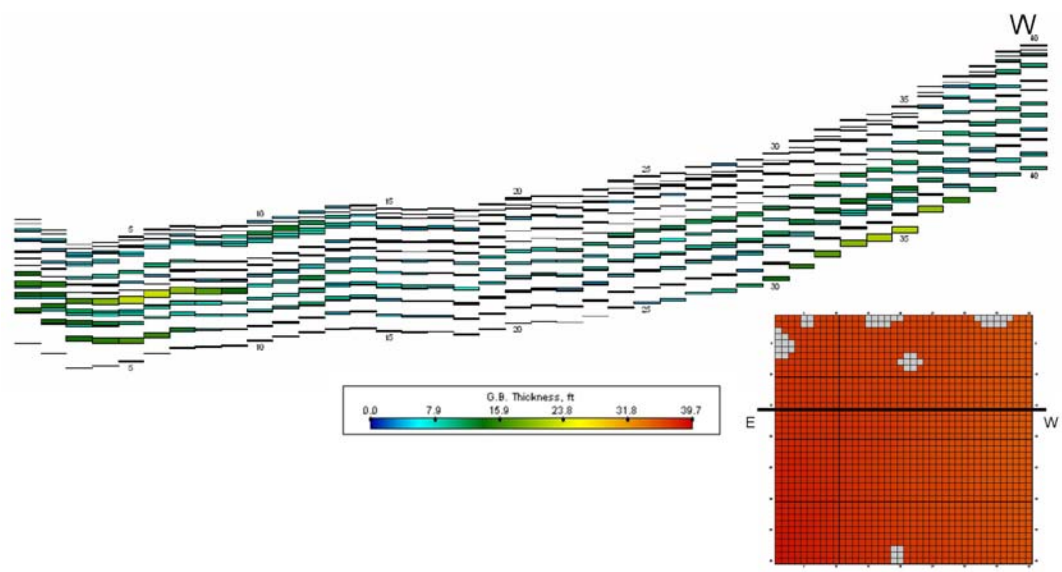


Fig. F-1. Cross-section from east to west along northern portion of model grid

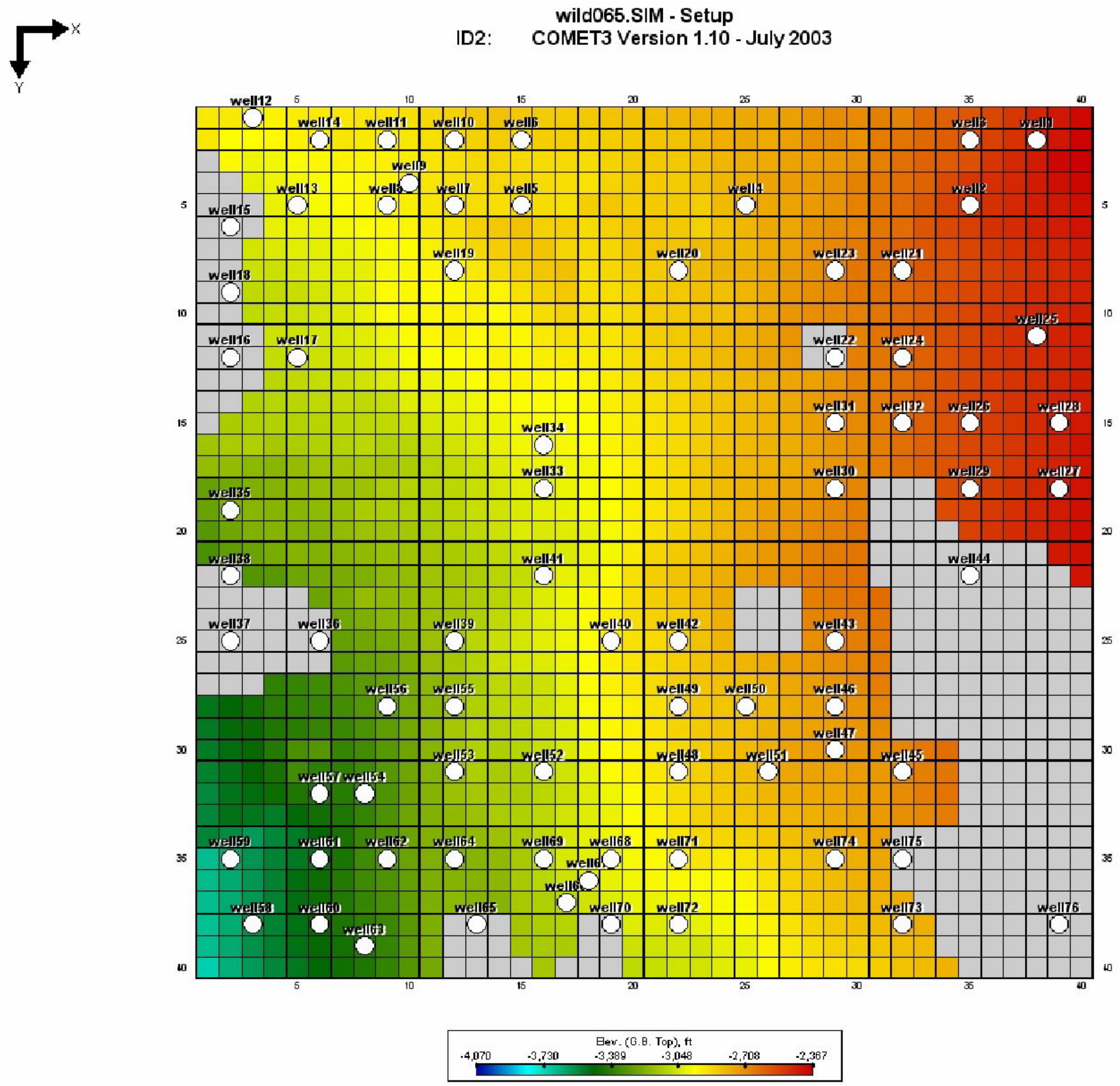


Fig. F-2. Structural map on top of layer one & distribution of active wells

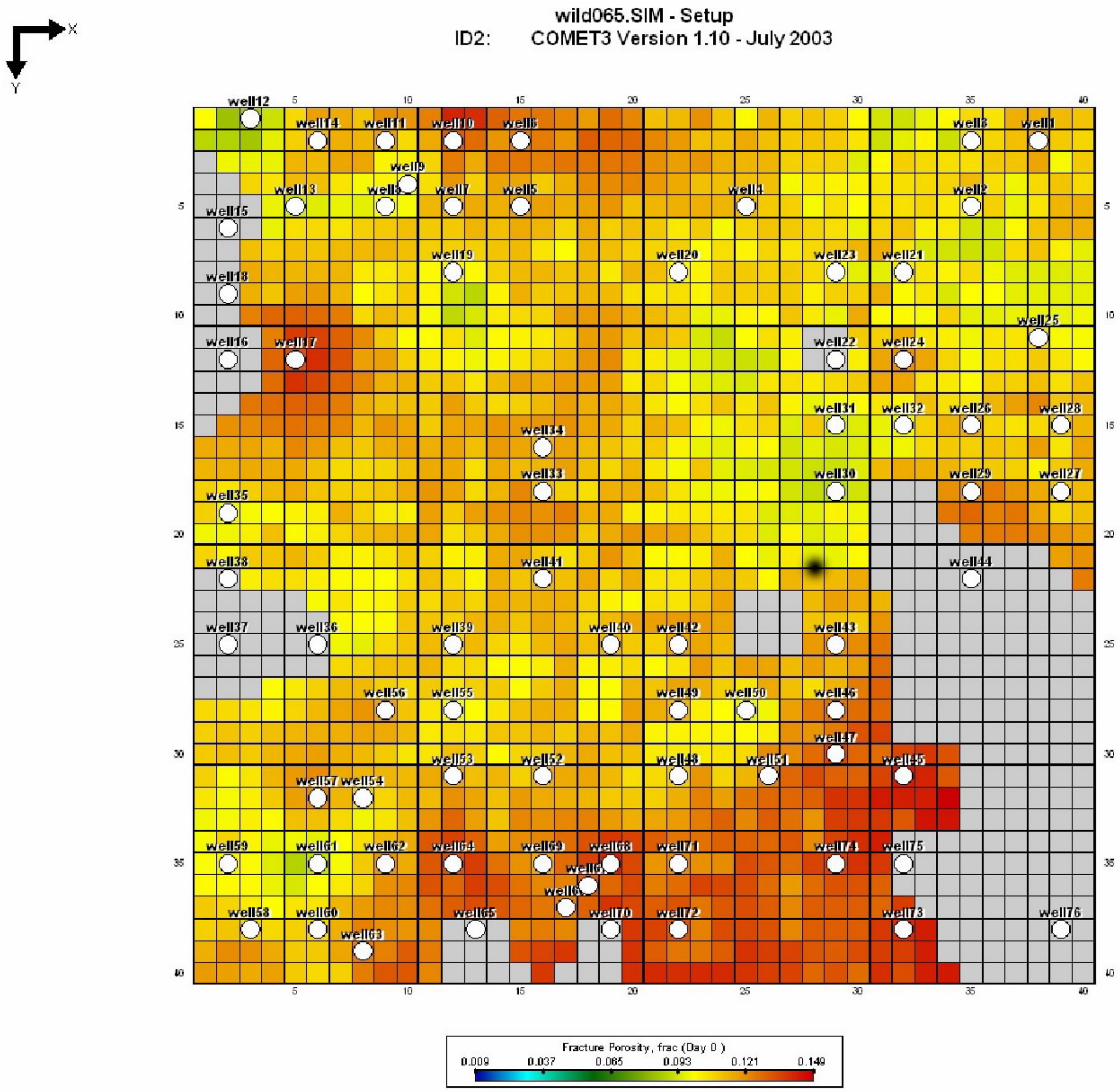


Fig. F-3. Porosity distribution in layer one

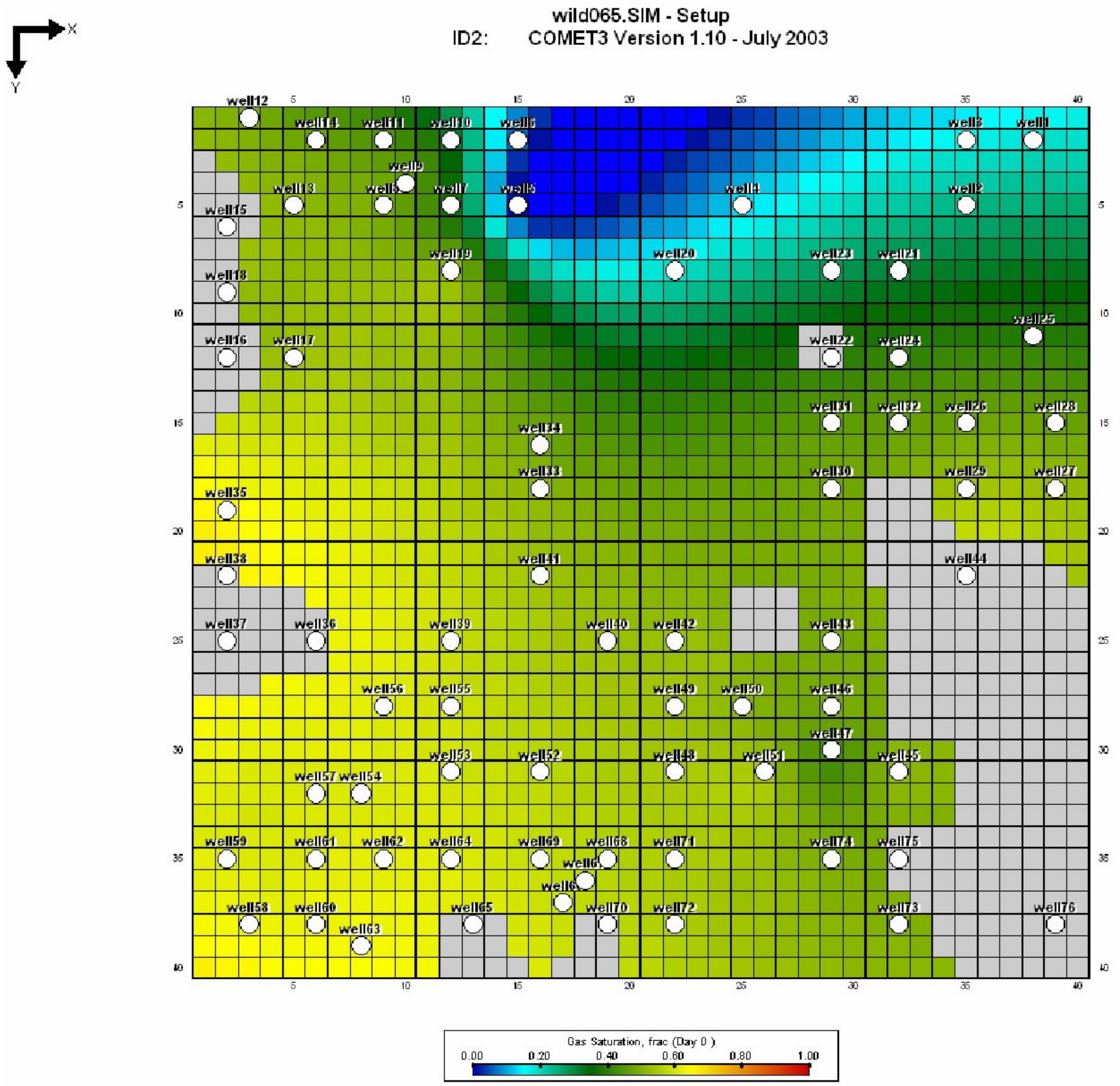


Fig. F-4. Gas saturation in layer one

Based on the individual structure and thickness of each of the model's twenty-three layers, pressure was determined based on an overpressured gradient of approximately 0.57 psi/ft (fig. F-5), taken from field data.

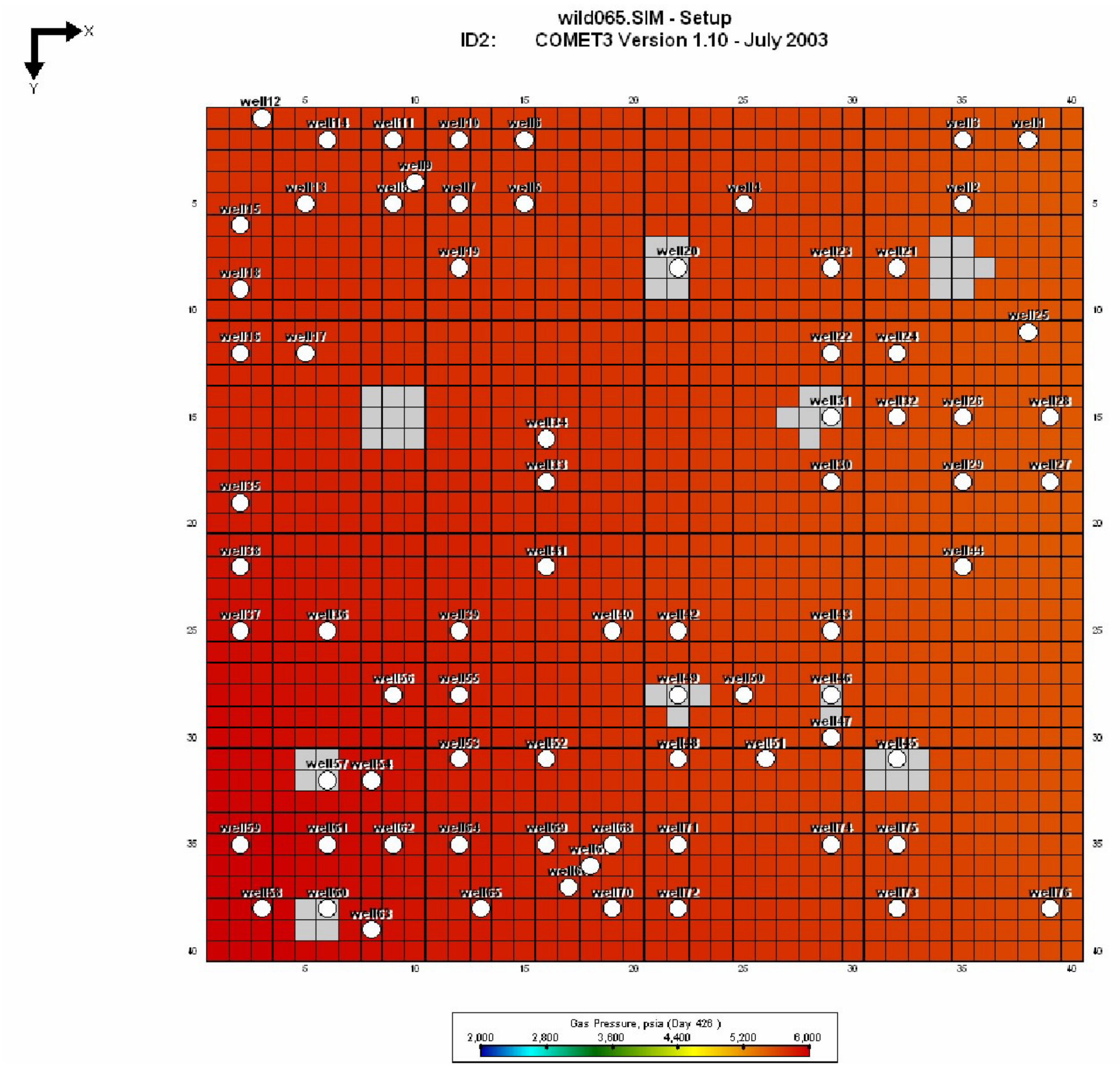


Fig. F-5. Initial gas pressure in layer 15

In order to populate the grid cells for the coal seams, constant porosity and water saturation data was employed. Parameters of 1% porosity and 100% water saturation respectively were employed. To provide a gas charge to the coal seams a representative coal isotherm was used in the model.

Coal gas content plotted against pressure is shown in fig. F-6.

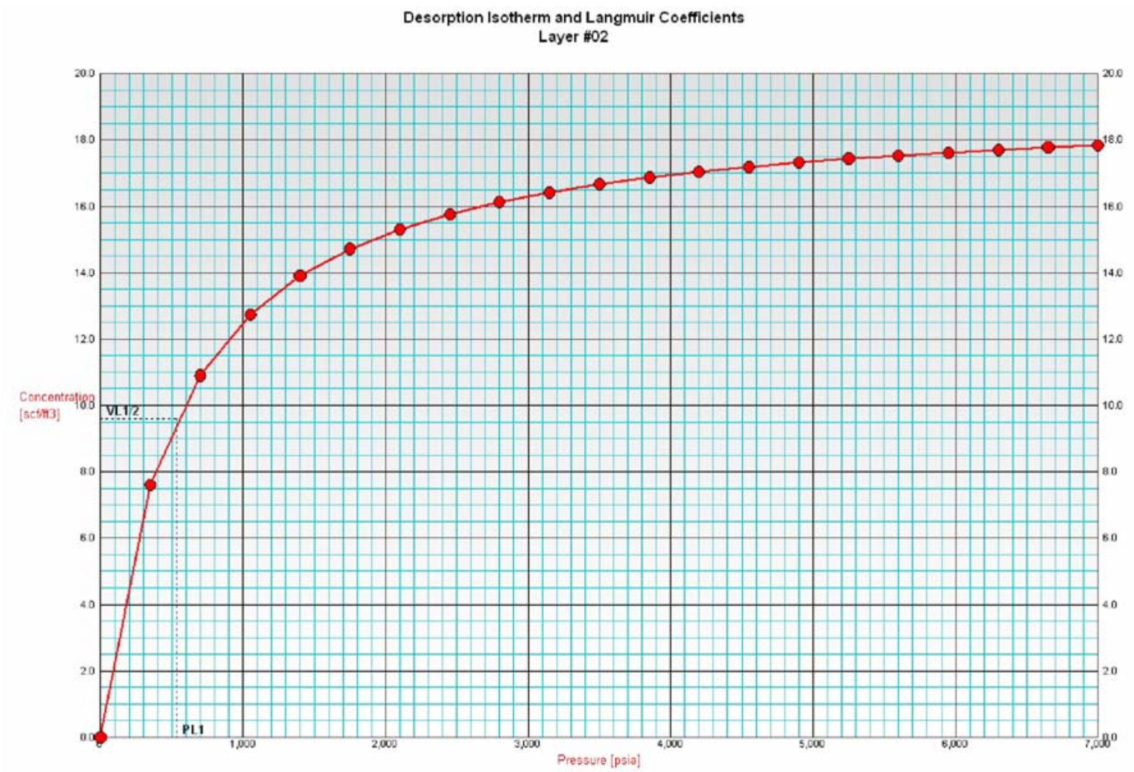


Fig. F-6. Coal desorption isotherm

The final data set input parameter for the grid system was reservoir permeability. While this parameter was held constant (spatially and vertically) for the coal beds, at 1 md, it was varied in the horizontal and vertical directions for the sand bodies. Permeability was supplied for the study area and in terms of fracture and matrix permeability for each grid cell.

These values were geometrically averaged for input in to the simulator as shown in fig. F-7.

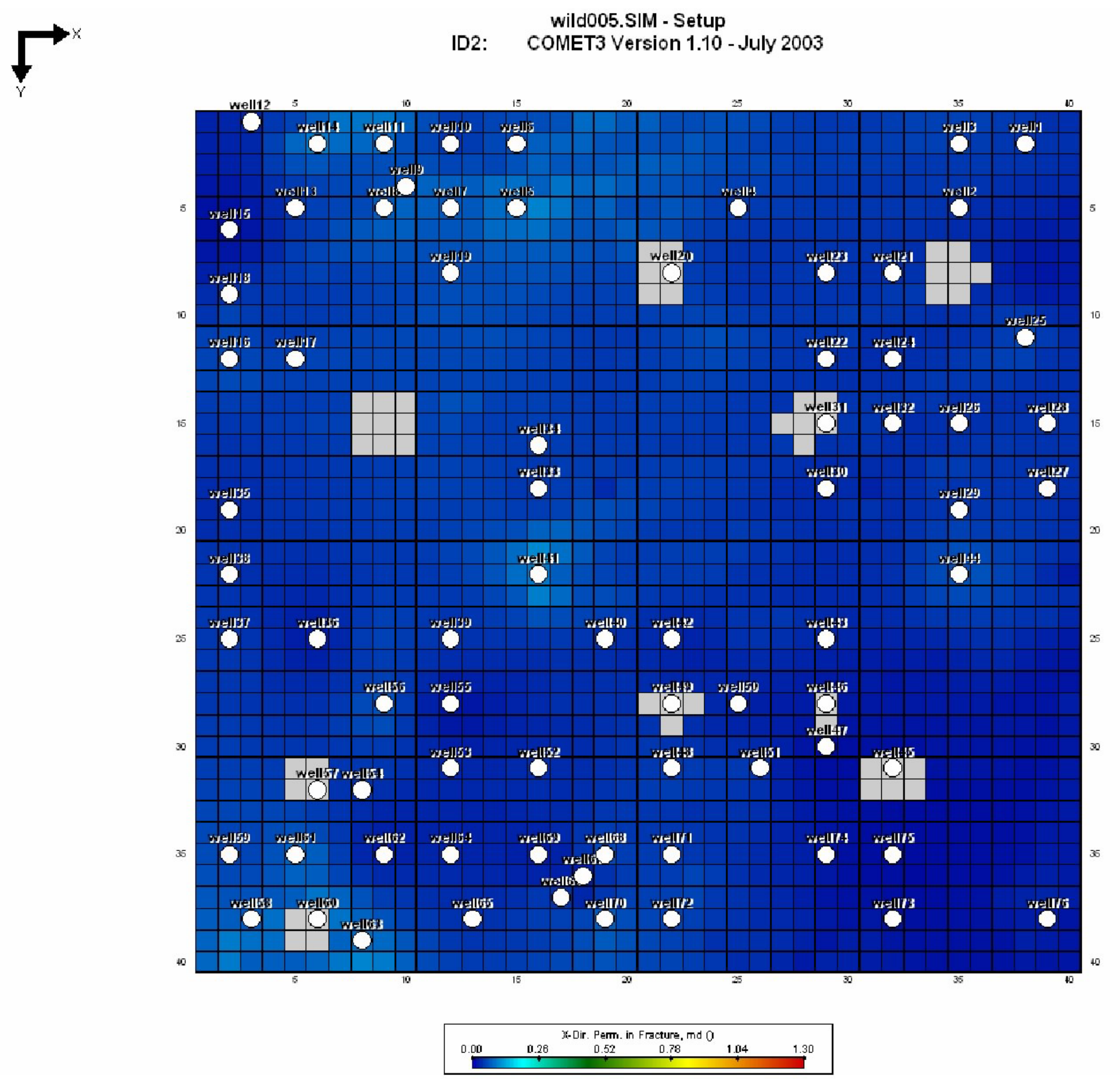


Fig. F-7. Initial permeability in Layer 15

Relative permeability was input into the model (fig. F-8) based on Byrnes' (2003) study of permeability, capillary pressure, and relative permeability properties.

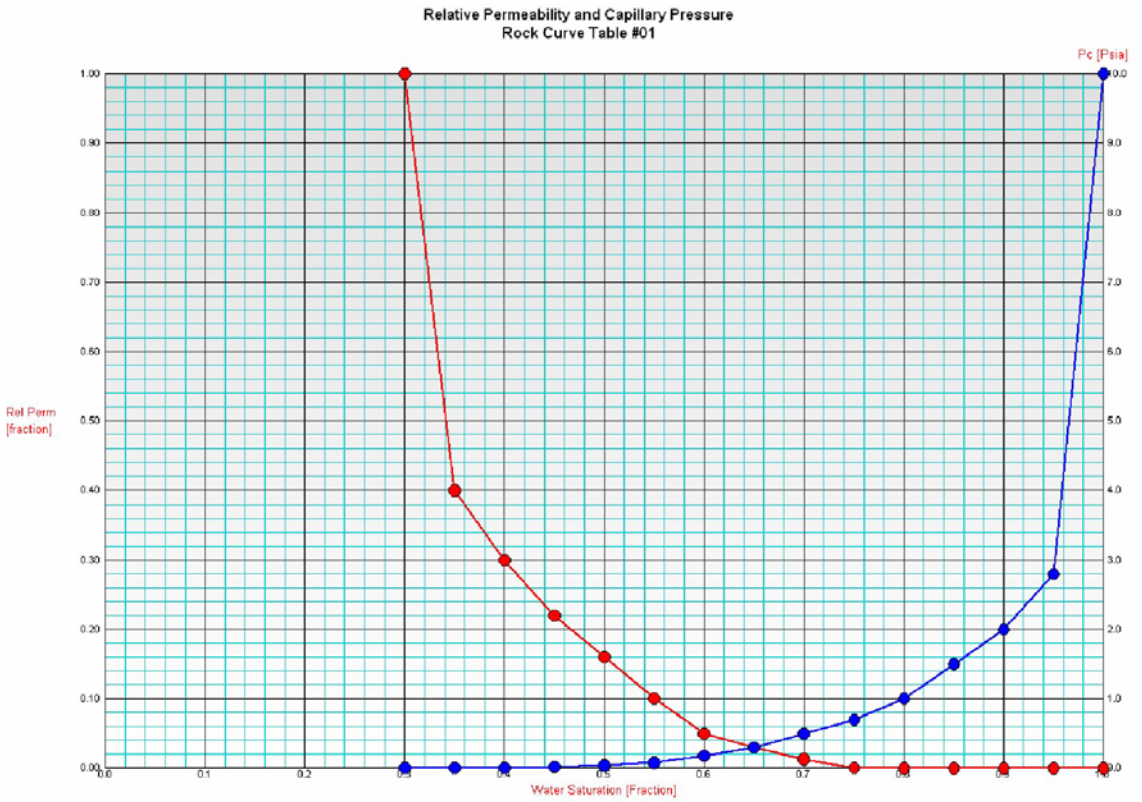


Fig. F-8. Relative permeability

As shown on figures F-2 through F-7 wells were located within the grid system per their field location. Detailed work went into specifying the well completion layers within the twelve sand reservoirs. While no coal seams were perforated in the model (to replicate field completion practices), sands were completed per industry-supplied data.

With nearly twenty-eight years of historical production data available for the Wild Rose area, wells were controlled through monthly gas rates. A secondary operational constraint was field-observed back pressures.

Initialization

An initial estimate of original gas in place (OGIP) was calculated using the reservoir geology at original conditions of pressure and saturation. (Table F-1). Overall, 1.1 tcf of gas and 820 billion bbl of water were estimated to be the study area. Noting that sand and coal bodies (odd and even layers, respectively) alternate within the model, nearly 60% of the original hydrocarbons in-place were estimated to have been contained in the sands, leaving the remaining 480 bcf in the adsorbed state within the coal seams. Field verification of the isotherm would determine if the estimate of gas in-place in the coal seams is accurate.

Table F-1. Initial gas and water in place for the 23 model layers

	Initial GIP (bcf)			Initial WIP
	Sorbed	Free	Total	(MMbbls)
layer 1	0	57.5	57.5	39,148.4
layer 2	9.2	0	9.2	916.1
layer 3	0	5.3	5.3	3,123.9
layer 4	0.2	0	0.2	19.4
layer 5	0	36.3	36.3	31,842.1
layer 6	37.8	0	37.8	3,780.3
layer 7	0	104.1	104.1	80,521.7
layer 8	46.5	0	46.5	4,641.3
layer 9	0	30.2	30.2	24,686.3
layer 10	86.8	0	86.8	8,661.0
layer 11	0	39.0	39.0	32,213.8
layer 12	37.9	0	37.9	3,782.2
layer 13	0	54.9	54.9	47,278.2
layer 14	98.7	0	98.7	9,853.0
layer 15	0	105.0	105.0	82,417.4
layer 16	2.2	0	2.2	223.0
layer 17	0	99.5	99.5	90,124.4
layer 18	99.9	0	99.9	9,964.2
layer 19	0	50.8	50.8	82,367.7
layer 20	49.1	0	49.1	4,901.3
layer 21	0	68.7	68.7	147,257.4
layer 22	13.8	0	13.8	1,382.0
layer 23	0	33.1	33.1	112,308.1
TOTAL	**482.1**	**684.4**	**1,166.5**	**821,413.4**

History Matching Procedure

Initial model runs were exceptionally time-consuming. To mitigate the time constraints of running such a large model, the first eighteen years of production controls were shifted from a monthly basis to an approximated quarterly basis, which effectively reduced the run time by 50%.

Initial results indicated the need to alter base input parameters to achieve an acceptable history match result (fig. F-9). We accepted the petrophysical analysis of the reservoir properties at face value, particularly since the OGIP was more than sufficient to model the production history. The primary adjustment for the history match was bulk permeability around the wellbores.

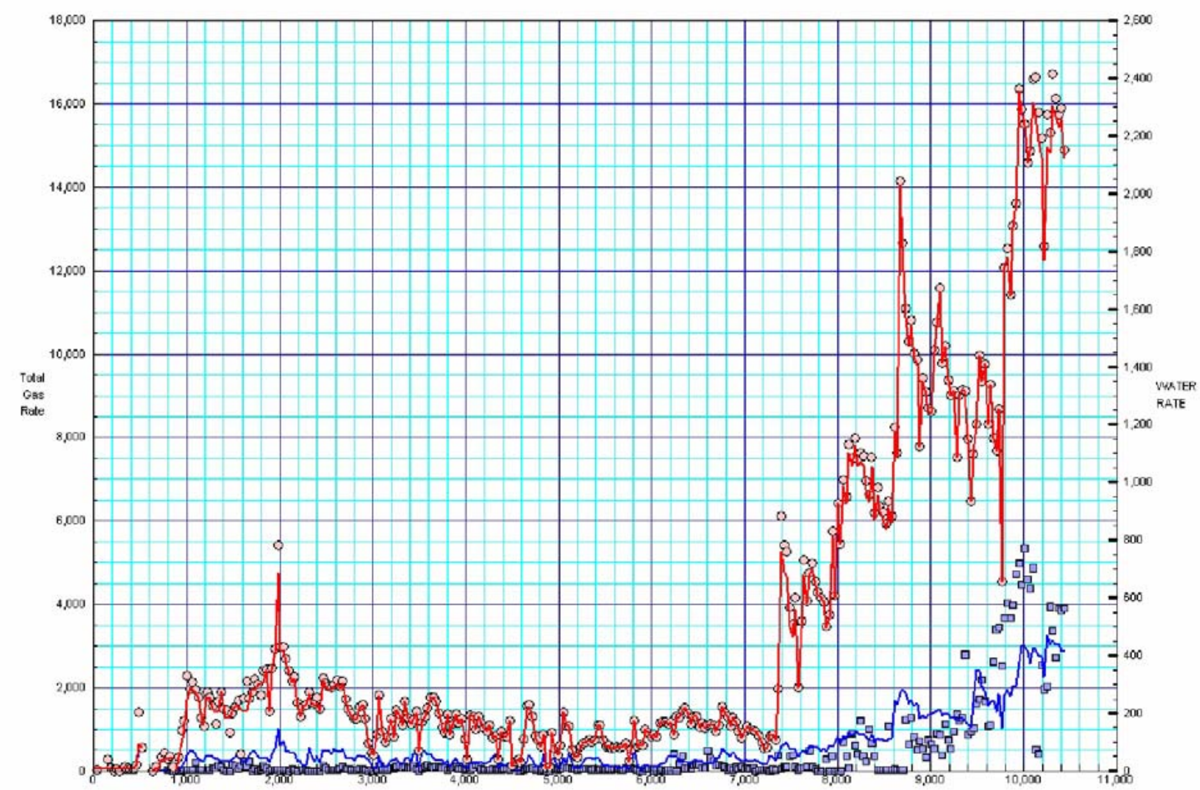


Fig. F-9. Gas & water rates versus historical gas & water rates

First, permeability values were adjusted on a "coarse" or regional basis across the vertically stacked sands, until the majority of wells across the area met gas rate and pressure specifications. Then, the matches were fine-tuned through near well adjustments to permeability.

Fig. F-10 shows the (a) pre-history match permeability array and (b) the post-history match for sand layer fifteen in the model.

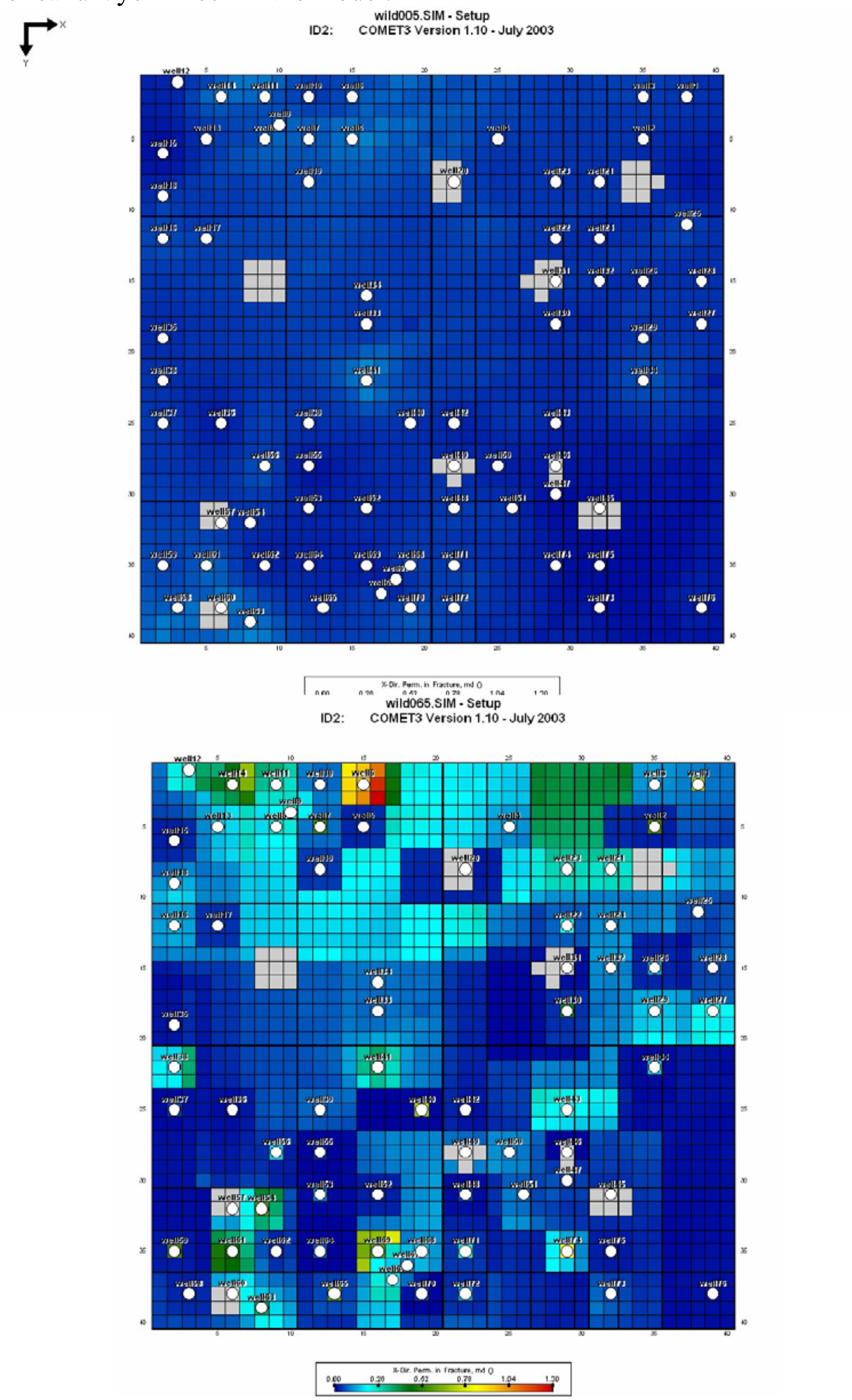


Fig. F-10. Permeability arrays before and after modifications (layer 15)

Fig. F-11 shows the resulting gas and water rate matches for the Wild Rose area.

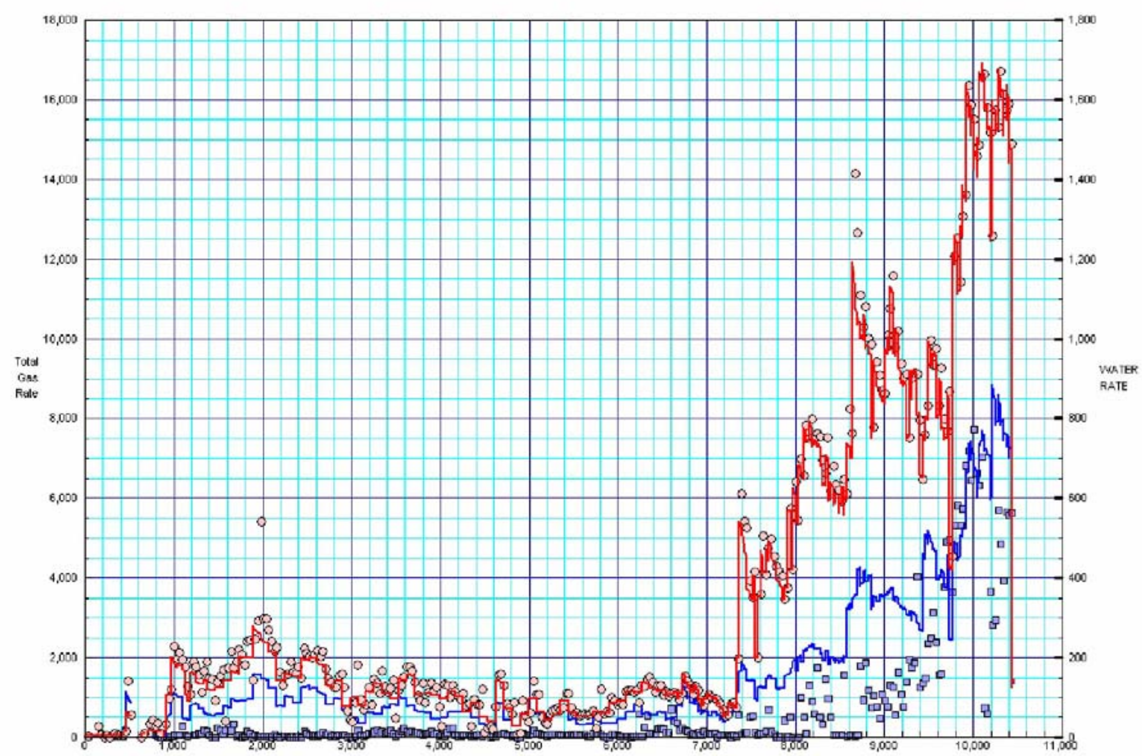


Fig. F-11. Gas & water rates versus historical gas & water rates after permeability adjustments

Results

While the field match was quite good, individual well matches were of variable quality. Fig. F-12 and illustrates good matches simulated for (a) gas, (b) water and (c) pressure. Fig. F-13 shows a poor match—a negligible variance based on the overall field match.

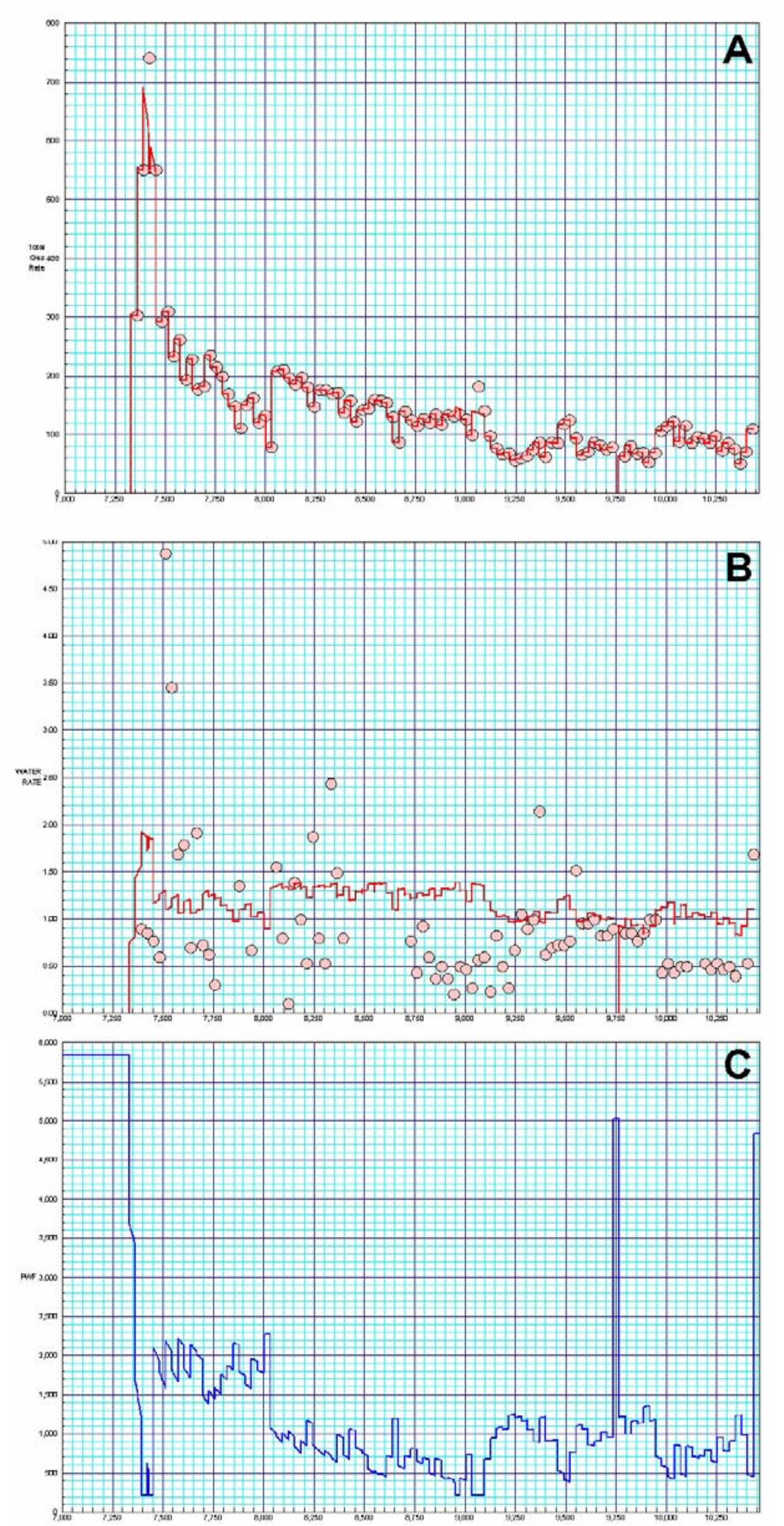


Fig. F-12. Well 55, an example of a good match, where both gas (A) & water (B) production rates are well-matched & pressure curve (C) is reasonable

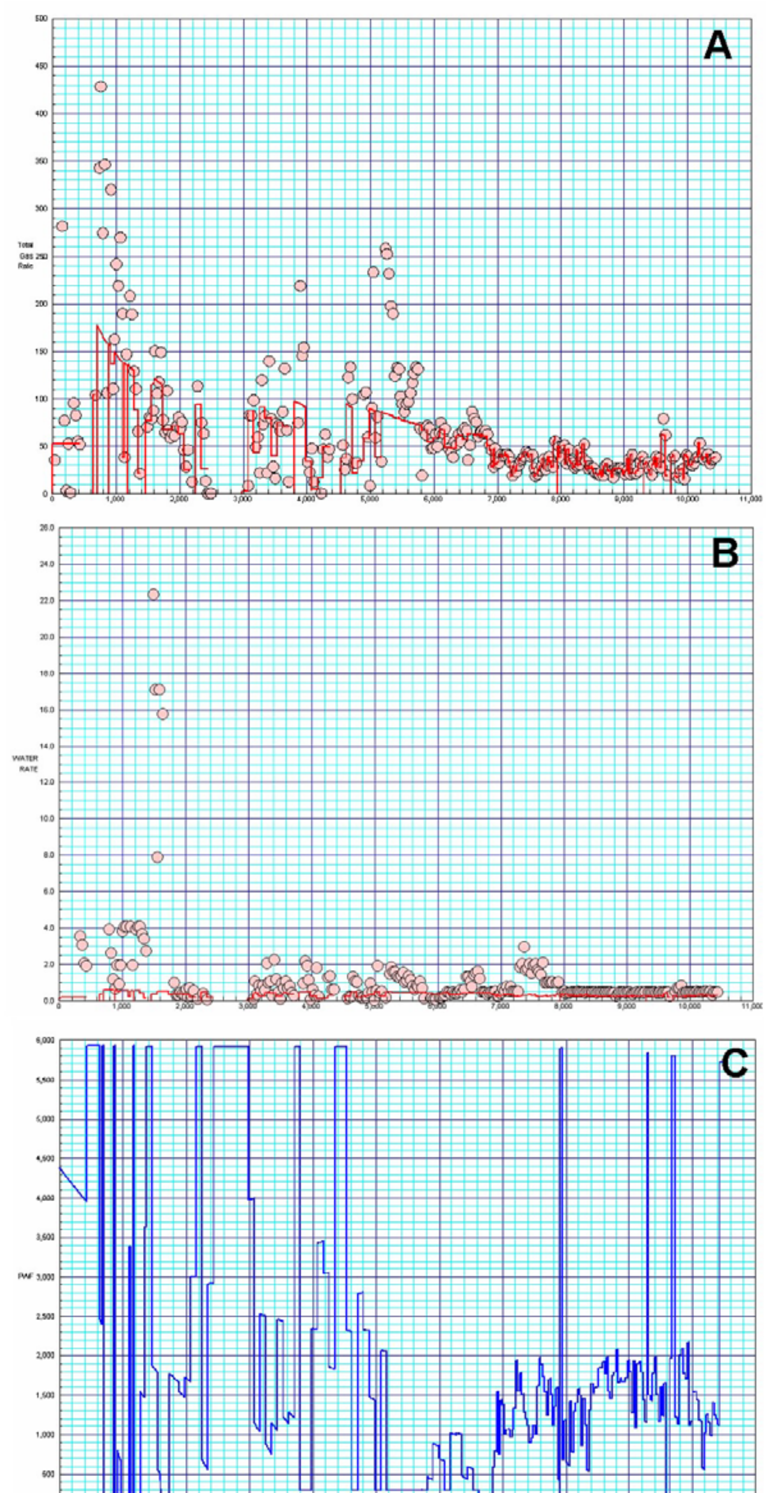


Fig. F-13. Well 63, an example of low quality match showing gas (A) & water (B) rates, & pressure curve (C), where water rate is underestimated & pressure curve is very sporadic

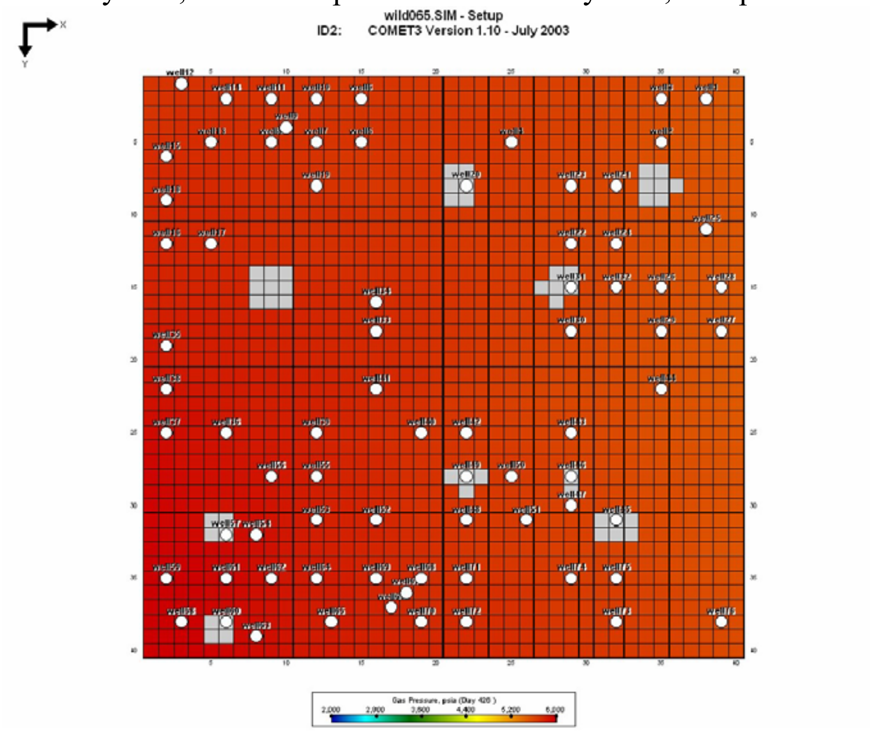
While Table F-1 presented initial fluids in-place, Table F-2 shows the by-layer contribution during twenty-three years of production.

Table F-2. By-layer voidage & cumulative gas recovered in field through October 2003

	Initial GIP (bcf)	Cumulative Gas Produced (bcf)	Gas Recovery Percent IGIP
layer 1	57.5	3.1	5.3
layer 2	9.2	0.0	0.0
layer 3	5.3	0.2	4.2
layer 4	0.2	0.0	0.0
layer 5	36.3	1.8	4.8
layer 6	37.8	0.0	0.0
layer 7	104.1	3.7	3.5
layer 8	46.5	0.0	0.0
layer 9	30.2	2.2	7.3
layer 10	86.8	0.0	0.0
layer 11	39.0	3.4	8.7
layer 12	37.9	0.0	0.0
layer 13	54.9	2.4	4.3
layer 14	98.7	0.0	0.0
layer 15	105.0	6.9	6.6
layer 16	2.2	0.0	0.0
layer 17	99.5	7.5	7.6
layer 18	99.9	0.0	0.0
layer 19	50.8	2.3	4.6
layer 20	49.1	0.0	0.0
layer 21	68.7	0.8	1.1
layer 22	13.8	0.0	0.0
layer 23	33.1	0.3	0.9
TOTAL	**1,166.5**	**34.5**	**3.0**

	Remaining Gas (bcf)
Sands (odd layers)	649.8
Coals (even layers)	482.1
TOTAL	**1,131.9**

It is important to note the insignificant contribution of coal seams to date. Sands have produced only 5% of their OGIP volume and 3% of the overall system in-place volume. Depletion in this system, shown via pressure for sand layer 15, is depicted in fig. F-14.



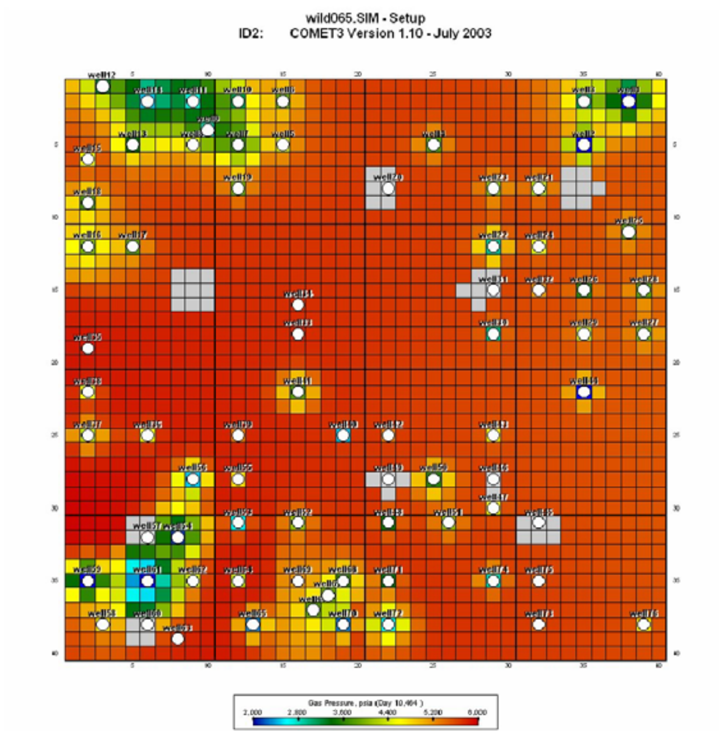


Fig. F-14. Initial to final gas pressure arrays (layer 15) depicting some edge effects & showing relative depletion for inter-grid wells

The cumulative gas and water production matches for the study area are shown in fig. F-15.

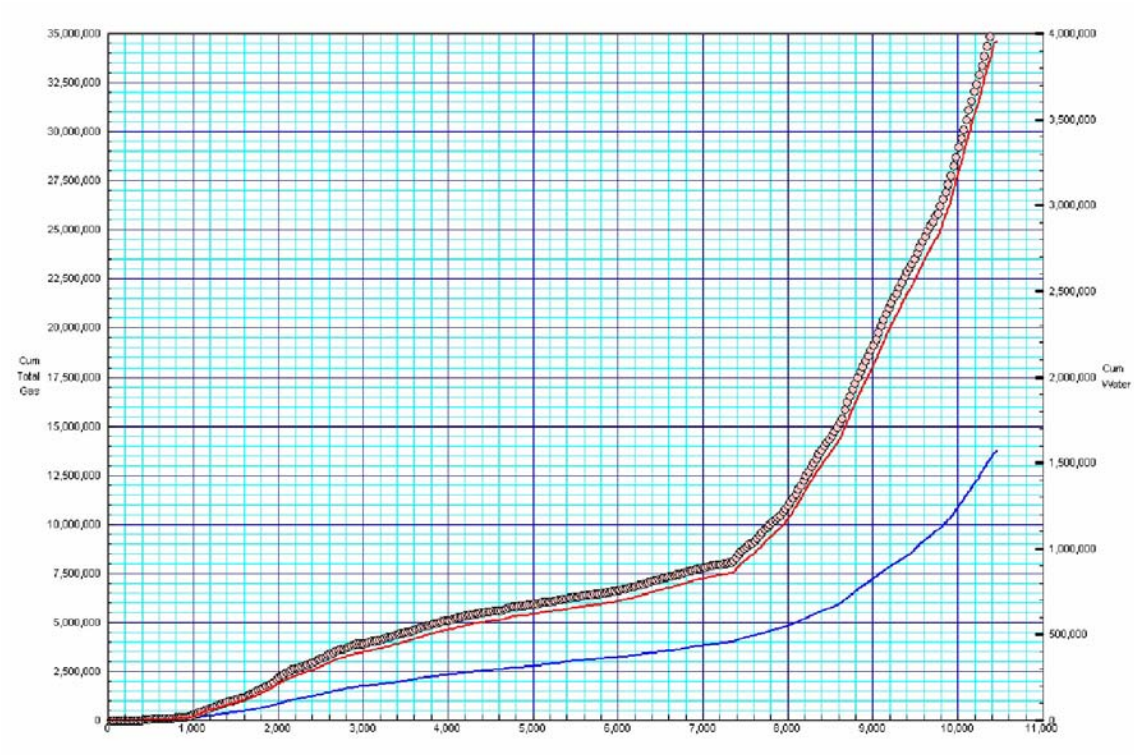


Fig. F-15. Final field-wide cumulative gas & water production

The history match regarding the Wamsutter as well as the quality of the history match suggests the following:

- Relatively low historical production and high OGIP suggests a large potential for infilling this area, which the operator is currently undertaking (eleven of seventy-nine wells planned are already drilled). Taking away edge effects, average well drainage appears to be eighty acres in the developed areas and interference appears to be minimal (fig. F-14). Therefore, the infill pattern development is justified.
- The coal seams have not contributed to the overall production. Confirmation of coal IGIP is necessary to better gauge the future contribution of these seams.
- The relative flow contribution of each area and/or additional spinner surveys in conjunction with measured bottomhole or wellhead flowing pressures could have narrowed the parameters of this history match.

Forecast

The mid-2005 Wild Rose area production forecast considered the production of the existing seventy-six wells previously described and matched, with permitted locations. Eleven wells drilled and completed during the simulation history matching effort were used for post appraisal, and the remaining sixty-eight permitted wells (at a completion rate of two per month, going forward) were added to the forecast.

The forecast run was projected for twenty-five additional years, through 2028. See fig. F-16 for the gas rate and cumulative gas forecasts for the 155 well run as compared to forecasting only the pre-existing seventy-six wells already matched in the base case.

This forecast estimates that peak gas rate will be on the order of thirty-five MMcfd and further suggests that cumulative gas production from the area will eventually surpass 200 bcf by 2035.

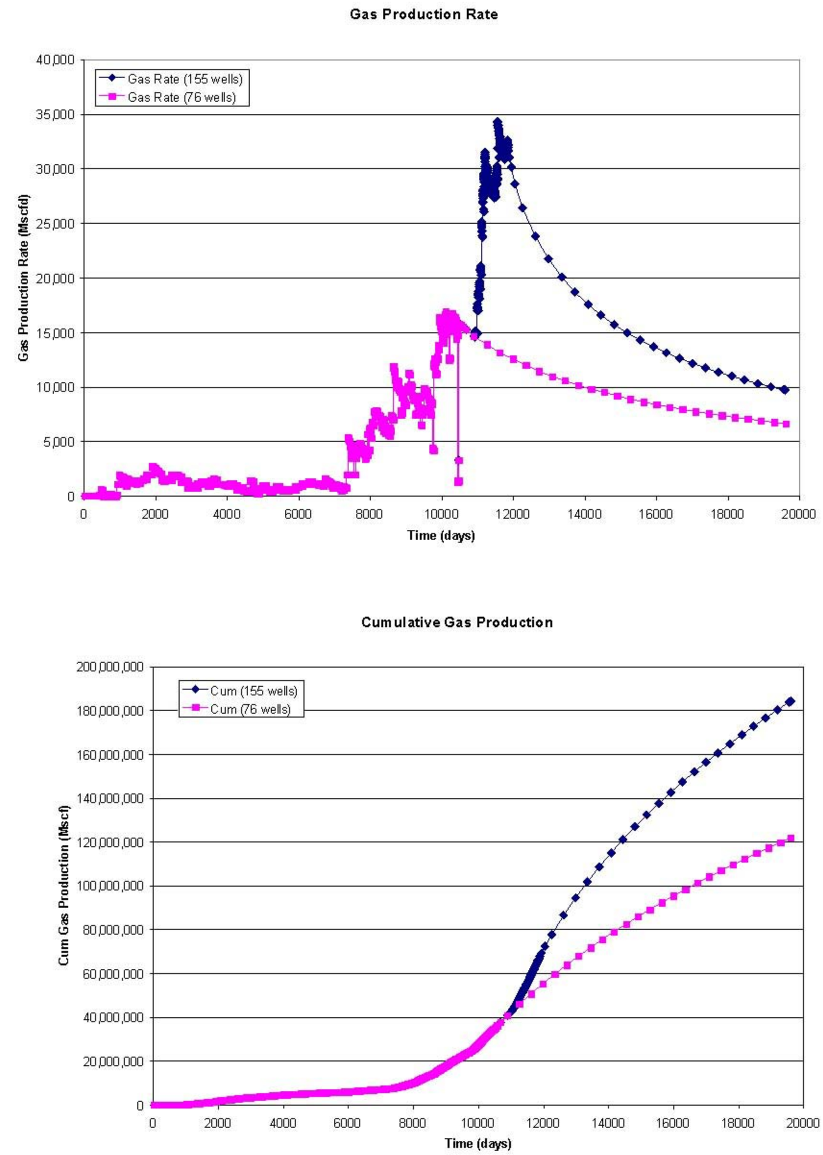


Fig. F-16. Gas rate (A) and cumulative gas (B) forecasts for 155 wells as compared to forecasting only pre-existing 76 wells

As a control, the cumulative gas production from the eleven new infill wells was compared to the forecast. The generally good results (figs. F-17 through F-19) suggest the history match may be an effective tool to predict infill potential and estimate future production.

However, the model should be updated to reflect the data gathered (via geophysical logs and production) and to minimize the difference between the forecast and actual field performance.

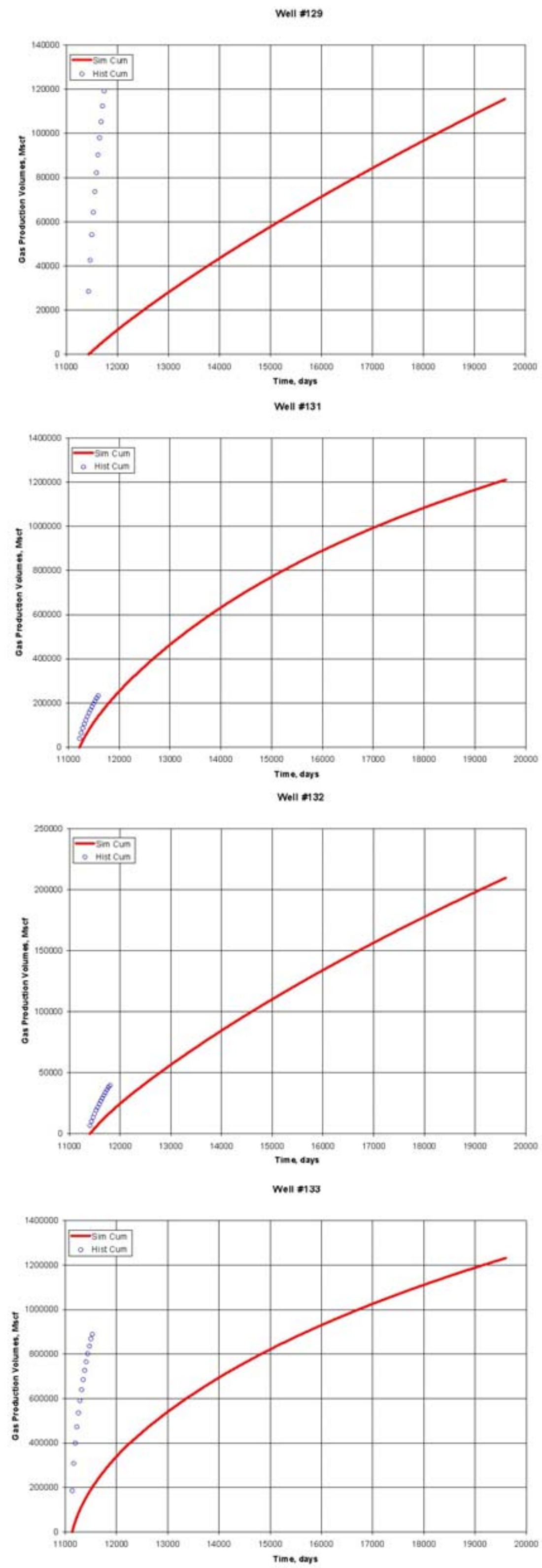


Fig. F-17. Comparison of cumulative gas production to forecasted production from new infill wells, cont'd.

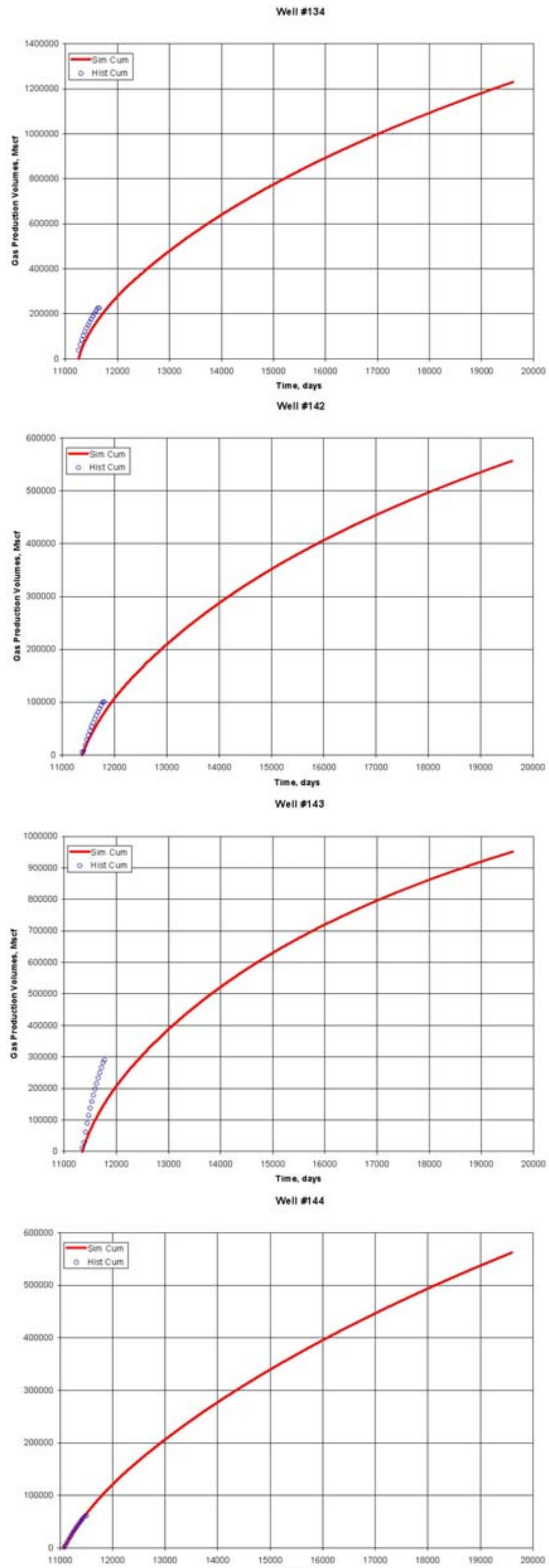


Fig. F-18. Comparison of cumulative gas production to forecasted production from new infill wells, cont'd.

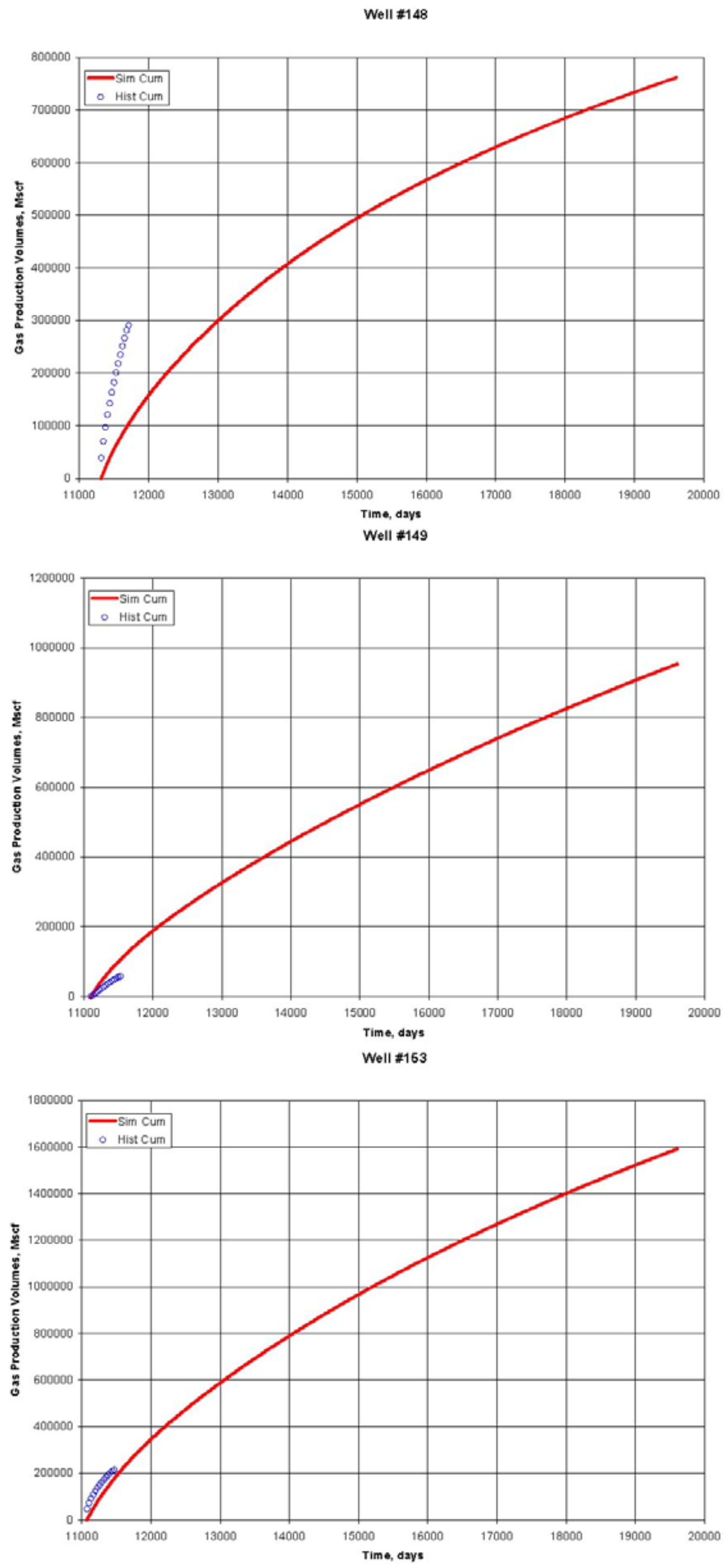


Fig. F-19. Comparison of cumulative gas production to forecasted production from new infill wells